UNITED ENERGY
Distribution

Appendix

ECM and EBSS Supplementary Material

United Energy Distribution
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Revision History

REV	REVISION STATUS	DATE	PREPARED	CHECKED	AUTHORISED
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1. TRANSITIONAL ARRANGEMENTS

1.1 Efficiency carry over mechanism

1.1.1 Transitional carry-over amount from 2006 to 2010 EDPR

United Energy has been subject to an efficiency carry-over mechanism (ECM) from 2006 to 2010. The scheme was devised by the Office of the Regulator-General for application over the 2001 to 2005 regulatory period, and then maintained by the ESCV from 2006 to 2010. The ECM is essentially an arrangement for sharing efficiency gains between distributors and their customers. An efficiency gain is a reduction in operating expenditure in any one year relative to forecast. The apportioning of the gains occurs because distribution businesses retain the savings from any under-spending within the regulatory period, but then participate in the transfer of these benefits to customers in the following regulatory period through lower projected levels of operating spending (and therefore lower prices).

A key component of the scheme, which ensures that customers receive their share of efficiency benefits, is the translation of revealed costs into forecasts. Distributors are also rewarded by being able to earn efficiency carry-over amounts in the subsequent regulatory period. The ECM is based on an incremental calculation method which was designed to ensure that rewards are only retained where efficiencies are sustainable.

In Volume I of the Final Decision, (ESCV 2005a), the ESCV stated that efficiency carry-over amounts would be calculated as follows:

- An efficiency gain (or loss) in operating and maintenance expenditure in any year during the 2006-10 regulatory period is to be calculated as the reduction (or increase) in the level of recurrent operating and maintenance expenditure compared to the forecast for that year. Recurrent in this context is interpreted to be the under-spend (or over-spend) between forecast and actual in year one, and then the incremental under-spend (or over-spend) in subsequent years.

UED has applied the calculation method to its forecast and actual figures for operating and maintenance (O&M) expenditure from 2006 to 2010. The results of the evaluation are presented below in Table 1.1. The dollar amounts for both benchmark and out-turn components have been inflated to give values in 2010 prices. The savings in O&M expenditure resulting from efficiency improvements implemented by UED are shown in the table. The incremental change from one year to the next is also presented. The forecast incremental change for 2010 has been zero rated at this juncture.

Table 1.1: Operating expenditure components of carry-over, EDPR 2006 to 2010

Values in $M		2006	2007	2008	2009	2010
O&M benchmark	$ 2004 prices	80.79	82.47	84.19	86.03	85.79
O&M benchmark	$ 2010 prices	95.85	97.86	99.89	102.08	101.79
Correction to O&M benchmark	$ 2010 prices	0.23	0.46	0.70	0.93	1.16
Growth adjusted O&M benchmark	$ 2010 prices	**96.09**	**98.32**	**100.59**	**103.00**	**-**
O&M Actual (out-turn)	$ current prices	82.58	80.85	84.67	92.64	90.98
O&M Actual (out-turn)	$ 2010 prices	92.94	87.55	90.01	93.81	96.02
Under-spend/(Over-spend)	$ 2010 prices	3.15	10.77	10.58	9.20	6.93
Year-on-year change in under/(over)	$ 2010 prices	3.15	7.62	-0.18	-1.39	-

Source: UED calculations and financial model for EDPR 2011 to 2015. Methods outlined in section 4.2, ESCV (2004a) and chapter 10, ESCV (2005a). No incremental gain or loss is shown for 2010 because actual O&M figures are not yet available (estimates are shown).

The incremental change for 2010 is shown as being zero, because the out-turn figures for O&M spending are clearly not available at this stage. The numbers for actual O&M spending in 2010 are estimates drawn from the UED financial model.

It will not be possible to calculate the incremental change accurately for 2010 in the middle of the next calendar year. However, UED expects that it will provide a revised non-zero estimate. To the extent that this estimate turns out to be inaccurate or incorrect, UED suggests that a correction factor be applied during the forthcoming regulatory period, from 2011 to 2015.

Table 1.2 shows the carry-over values for the 2011 to 2015 regulatory period that have been assessed using the incremental change results from Table 1.1 above. The efficiency carry-over in each year is the sum of selected carry forward components from the 2006 to 2010 regulatory period. A positive net carry-over is anticipated for each year from 2011 to 2014.

The undiscounted sum of the carry-over values in Table 1.2 is equal to $12.28 million. UED has used a pre-tax WACC of 6.3% (sourced from ESCV, 2005b) to discount the values for each year back to 2011, the first year of the forthcoming regulatory period. The net present value in 2011 of the carry-over amounts in Table 1.2 is equal to $12.34 million. UED submits this figure for inclusion in its building block revenue requirement for the 2011 to 2015 regulatory period.

Table 1.2: Assessed carry-over values from EDPR 2006 to 2010

Values in $ million		2011	2012	2013	2014	2015
Carry-over amounts from years:	$ 2010 prices					
2006		3.15	-	-	-	-

Values in $ million		2011	2012	2013	2014	2015
2007		7.62	7.62	-	-	-
2008		-0.18	-0.18	-0.18	-	-
2009		-1.39	-1.39	-1.39	-1.39	-
2010		0.00	0.00	0.00	0.00	0.00
Sum of efficiency carry-over		9.20	6.05	-1.57	-1.39	0.00

Source: UED calculations and financial model for EDPR 2011 to 2015. Methods outlined in section 4.2, ESCV (2004a) and chapter 10, ESCV (2005a).

1.1.2 Explanation of the growth adjustment applied to the operating expenditure benchmarks

When estimating operating expenditure savings, for the purpose of calculating an efficiency carry-over, it is necessary to ascertain the extent to which differences between forecast and out-turn operating spending are attributable to a changed customer or energy demand profile. Distribution businesses do not seek to claim an efficiency carry-over for savings in O&M spending which are realised because out-turn growth in peak energy demand or overall energy consumption is lower than anticipated.

Accordingly, a method has been devised to implement ex-post revisions to O&M expenditure allowances so as to correct for changed volume drivers. The method essentially recognises that forecasts of the main quantity variables may not always be accurate, or else may not be borne out because of a changed economic environment.

The Essential Services Commission (ESCV, 2005a) relied upon the technique of partial factor productivity (PFP) to determine the contribution of the main customer driven variables to changes in total recurrent costs. Partial Factor Productivity growth is the change in productivity arising from a change in a given input, such as labour, assuming all other inputs are held constant.

The ESCV drew upon a report by Pacific Economics Group (PEG) which had been prepared for SP Ausnet (PEG, 2004). According to the ESCV:

> " The change in partial factor productivity (PFP) is calculated by the difference between the change in [overall] operating and maintenance expenditure and the change in operating and maintenance expenditure driven by [movements] in growth factors such as customer numbers, energy consumption and peak demand. The change in operating and maintenance expenditure driven by [alterations to] growth factors was determined by multiplying the annual change in the key network drivers of customer numbers, energy consumption and peak demand, by the weights or estimated coefficients computed for these same network drivers by Pacific Economics Groups (PEG) on behalf of SP AusNet, based on Victorian data. The estimated coefficients were 0.431 for customer numbers, 0.296 for energy consumption and 0.272 for peak demand."

(The full text is available from Box 6.1, ESCV 2005a).

Pacific Economics Group (PEG, 2004) compiled an index of growth in the productivity of O&M inputs, $\dot{PFP}_{OM}$, which was based upon the following formulation:

$$\dot{PFP}_{OM} = \dot{Y}^{\varepsilon} - \dot{X}_{OM}$$ **Equation 1.1**

Where:

$\dot{PFP}_{OM}$ = An index of growth in the productivity of O&M inputs.

$\dot{Y}^{\varepsilon}$ = An elasticity-weighted output quantity index.

$\dot{X}_{OM}$ = An index of growth in the input quantity index.

The PFP index, $\dot{PFP}_{OM}$, can be used to formulate output growth projections.

The growth rate of the output quantity index is a weighted average of the growth rates of the output quantity measures. The weight for each output measure i is the share of the corresponding cost elasticity in the sum of the output-related cost elasticities.

The growth of the input quantity index can be shown to be the difference between the rate of growth of overall costs and the growth rate of an input price index, $\dot{W}_{OM}$.

$$\dot{X}_{OM} = \dot{C}_{OM} - \dot{W}_{OM}$$ **Equation 1.2**

Where:

$\dot{C}_{OM}$ = The growth rate of actual cost.

$\dot{W}_{OM}$ = The growth rate of an input price index.

The growth rate of the input quantity index is equal to the increase in operating spending which isn't a consequence of the growth in the prices of O&M inputs. The input price index was constructed from actual rather than optimal cost shares.

PEG computed the change in the input price index as a weighted average of the growth in the prices of two categories of O&M inputs - technical labour and other miscellaneous inputs. Data on input prices was provided by SP-Ausnet. The weights chosen were the shares of the input categories in the operating expenditure summed across all Victorian electricity distributors.

The industry-wide PFP growth rate for operating and maintenance expenditure made use of an average of the O&M spending figures reported by the Victorian electricity distributors, over the period from 2000 to 2004.

An important component in $\dot{PFP}_{OM}$ is the elasticity-weighted output quantity index, denoted above as $\dot{Y}^{\varepsilon}$. A transcendental logarithmic (translog) function was used to estimate the elasticity of costs with respect to output for the individual output variables. The cost function is represented by equation (22) in PEG (2004). The cost equation was estimated econometrically so that the parameter estimates for individual variables and for the cross-product terms (based on combinations of variables) could be obtained. The output-related cost elasticities were then obtained as partial derivatives of the translog with respect to each of the individual output variables. Mean values of the explanatory variables are normally substituted into the partial derivative.

The cost and quantity data used in the empirical work was sourced from the Federal Energy Regulatory Commission (FERC). PEG reports that investor-owned electricity utilities in the USA are required to submit regulatory accounts to the Commission on annual basis (PEG, 2004). The data reported on Form 1 must conform to the Uniform System of Accounts established by FERC.

The subset of data considered for inclusion in the sample was drawn from utilities which satisfied two criteria vis-à-vis the lodgement of their accounts:

- The Form 1 file had been lodged in 2003; and
- The particular entity, in conjunction with any significant predecessor companies, had reported the data continuously since the mid-1960s.

Furthermore, PEG reports that the data had to be plausible (PEG, 2004). Data from 75 companies was deemed to meet the standards adequately and was used in the indexing work. The econometric analysis made use of data from 72 companies.

PEG estimated several different versions of the translog equation using different combinations of the output measures as the explanatory variables (regressors). In some estimations, only a single output variable was used, and the results from these equations are reported below in Table 1.3. In other cases, two or more output variables were used as regressors. It should be noted that the translog has cross-product terms for the output variables. The ESCV chose to use the results from only the single variable models. In all cases, the dependent variable (on the left hand side of the equation) was total cost.

Table 1.3: Output-related cost elasticities from the translog function

Output measure	Output measure units	Cost elasticity	T-statistic	Adjusted R-squared	Normalised elasticities
Customer numbers	Millions	0.828	6.649	0.849	0.43136
Delivered energy volumes	GWh	0.569	2.895	0.738	0.29627
Peak demand	MW	0.523	2.530	0.727	0.27237

Output measure	Output measure units	Cost elasticity	T-statistic	Adjusted R-squared	Normalised elasticities
Line length	Km	0.042	0.358	0.684	n/a

Source: Results tables accompanying PEG (2004), provided by PEG in private correspondence. Notes: The t-ratios were calculated using the delta method. The data used for estimating (and therefore calibrating) the translog was compiled from U.S. electricity utilities. The normalised elasticities were worked out by the ESCV and were calculated from single output variable models including each of the first three output measures. The effect of the fourth variable, line length, is statistically insignificant as evidenced by the low t-ratio for the cost elasticity.

The calculated elasticities are presented in Table 1.3 rather than the raw parameter estimates. The adjusted R-squared is a measure of the goodness-of-fit of the estimated equations, with values close to one indicating a good fit to the data. High t-ratios imply strong statistical significance of the particular elasticity. The normalised elasticities were estimated by the ESCV, drawing upon the results recorded for the main output variables, customer numbers, delivered energy volumes and the level of peak demand. Essentially, the ESCV constrained the sum of the elasticities for the three variables to sum to one. The influence of line length was considered to be minimal, as evidenced by a low t-ratio.

The percentage change in the output quantity index was then worked out as follows:

$$\ln\left(\frac{Output\ quantities_t}{Output\ quantities_{t-1}}\right) = \sum_i SE_i \times \ln\left(\frac{Y_{i,t}}{Y_{i,t-1}}\right)$$

Equation 1.3

Where:

$SE_i =$ The share of output category i in the sum of the estimated, output-related cost elasticities. As previously noted, the elasticity values were obtained by partially differentiating the translog function, and then evaluating the result at mean values of the explanatory variables.

And, in each year t:

$Output\ quantities_t =$ Output quantity index.

$Y_{i,t} =$ Quantity sub-index for output category i.

Equation 1.3 is represented by equation (15a) in PEG (2004). The sum of the components on the right hand side of the equation essentially gives a percentage result, which the ESCV described as a growth adjustment coefficient. The formulation for the growth adjustment, shown on page 436 of ESCV (2005a) is as presented below:

Growth adjustment = PFP coefficient weightings × percentage change in growth

$$\begin{aligned} Growth\ adjustment = \ & 0.431 \times (\log\ natural\ change\ in\ customers) + \\ & 0.272 \times (\log\ natural\ change\ in\ peak\ demand) + \\ & 0.296 \times (\log\ natural\ change\ in\ energy\ consumption) \end{aligned}$$

Where:

0.431 is the PFP coefficient weighting associated with customer numbers.

0.272 is the PFP coefficient weighting associated with peak demand.

0.296 is the PFP coefficient weighting associated with consumption.

The coefficient weightings are the elasticities calculated using parameter estimates and mean variable values from the translog function, as described above.

The ESCV recommended that the overall growth adjustment coefficient should be applied in future calculations involving the efficiency carry-over mechanism. Specifically, the ESCV stipulated that the growth adjustment coefficient should only be applied to the base component of the O&M expenditure projections and not to figures which would be net of step changes.

The growth adjustment would help to ensure that distributors were only rewarded for genuine efficiency improvements resulting in cost savings. The objective would be achieved because the operating expenditure data is expunged of the effects of both a changed customer profile, and variations from forecast in energy usage and peak demand.

1.1.3 Application of the growth adjustment method to operating expenditure benchmarks

UED has followed the approach propounded by the ESCV when adjusting benchmark O&M forecasts for the purpose of calculating the allowed efficiency carry-over. The derivation of the growth adjustment coefficient is presented in Table 1.4. The first part of the table deals with the benchmark forecasts, while the second part addresses actual outcomes. The numbers in the rows entitled "weighted average, growth rates" are, as suggested, a weighted average of the results recorded, respectively, for customer numbers, peak demand and energy consumption.

In the final column, a simple geometric average is taken of the annual results from 2006 to 2009. The growth adjustment factor, -0.2619%, is obtained by subtraction of the results based on actual outcomes from the results based on forecast data. A negative value is reported because peak demand for electricity increased more strongly than expected over the period from 2006 to 2009. Consequently, the weighted average result for actual growth rates (2.039%) was above the weighted average result for forecast growth rates (1.777%).

The pace of growth in customer numbers and overall energy consumption was somewhat below the trajectory anticipated in the context of the pricing determination undertaken in 2005.

Table 1.4: Derivation of the growth adjustment for operating expenditure

	2005	2006	2007	2008	2009	2010	Av 2006 to 2009
Benchmark Forecasts							
Customer numbers	609,840	620,236	626,580	633,712	640,066	646,111	
Log (natural change in customers)		1.690%	1.018%	1.132%	0.998%	0.940%	1.209%
Peak demand (MW)	2,392	2,471	2,550	2,617	2,682	2,754	
Log (natural change in peak demand)		3.249%	3.147%	2.594%	2.453%	2.649%	2.861%
Energy consumption (GWh)	7,545	7,665	7,817	7,943	8,046	8,161	
Log (natural change in consumption)		1.585%	1.955%	1.600%	1.285%	1.426%	1.606%
Weighted average, growth rates		2.084%	1.875%	1.669%	1.479%	1.549%	1.777%
Actual Outcomes							
Customer numbers	602,321	605,572	610,876	616,544	620,545	625,181	
Log (natural change in customers)		0.538%	0.872%	0.924%	0.647%	0.744%	0.745%
Peak demand (MW)	2,057	2,154	2,249	2,392	2,553	2,600	
Log (natural change in peak demand)		4.576%	4.335%	6.147%	6.516%	1.841%	5.393%
Energy consumption (GWh)	7,557	7,814	7,888	7,913	7,814	7,788	
Log (natural change in consumption)		3.353%	0.942%	0.307%	-1.252%	-0.331%	0.838%
Weighted average, growth rates		2.472%	1.836%	2.164%	1.683%	0.724%	2.039%
Growth adjustment factor							-0.2619%

Source: UED calculations and financial model for EDPR 2011 to 2015. Partial Factor Productivity (PFP) coefficient weightings derived from "Predicting Growth in SPI's O&M expenses" (PEG, 2004).

In Table 1.5, the growth adjustment coefficient is transformed into dollar values. The starting point for the computation is the benchmark O&M figures measured in 2004 prices before a consideration of step-changes. It should be noted that the values recorded in the final row of Table 1.5 are the same as those employed in Table 1.1 to adjust the original O&M forecasts, albeit with no minus sign. The minus sign has been removed because Table 1.1 measures under-performance as a positive value.

The growth adjustment has the effect of broadening the gap between forecast and actual values of operating and maintenance expenditure. Intuitively, UED was successful in achieving operating expenditure savings even though the rate of increase in peak demand over the period was higher-than-expected. A wider margin between forecast and actual O&M values in the first year of the regulatory period gives rise to a higher efficiency carry-over. The magnitude of carry-over values computed for subsequent years depends upon the incremental change.

Table 1.5: Evaluating the dollar value of the growth adjustment

Values in $ million		2006	2007	2008	2009
Base O&M expenditure, no step-changes	$ 2004 prices	74.86	74.86	74.86	74.86
Growth adjustment factor		-0.262%	-0.262%	-0.262%	-0.262%
Impact of growth	$ 2004 prices	-0.1961	-0.1956	-0.1951	-0.1945
Cumulative impact of growth	$ 2004 prices	-0.1961	-0.3916	-0.5867	-0.7812
Cumulative impact of growth	$ 2010 prices	-0.2326	-0.4647	-0.6961	-0.9269

Source: UED calculations and financial model for EDPR 2011 to 2015. Partial Factor Productivity (PFP) coefficient weightings derived from "Predicting Growth in SPI's O&M expenses" (PEG, 2004).

2. APPLICATION OF INCENTIVE MECHANISMS

2.1 Efficiency benefit sharing scheme

2.1.1 Rule Requirements

Pursuant to clause 6.5.8 of the Rules, the AER has developed an Efficiency Benefit Sharing Scheme (EBSS) to apply to distribution businesses across Australia, during the next regulatory control period. The underlying intent of the EBSS is to give distributors incentives to manage their networks more efficiently and thereby moderate the growth in operating expenditure. The scheme also countenances potential reductions in O&M spending. Efficiency gains (or losses) resulting from the scheme are shared with network users over time. Initially, a distribution business will gain because direct savings or, alternatively, carry-over amounts, are made available to the entity for five years commencing from when O&M reductions are first achieved. However, consumers will also benefit progressively from decreases in approved operating expenditure forecasts, which will potentially be manifested as tariff reductions.

In aggregate, the AER has assessed that efficiency gains (or losses) will be shared between distribution businesses and distribution network users in a ratio of 30:70.

Clause 6.5.8(b) of the Rules permits, but does not oblige, the AER to develop a scheme which also covers efficiency gains and losses related to capital expenditure and/or distribution losses. However, the AER has signalled that it will only give its imprimatur to a scheme based on recurrent, operating expenditure. In clause 5.6.1.2 of the Framework and Approach paper for Victoria (AER, 2009e1), the AER has stated that the EBSS will not extend to capital outlays. Furthermore, in clause 5.3.2 of the Final Decision for the EBSS (AER, 2008f1), the AER has stated that it will not apply the EBSS to capital expenditure in the current round of regulatory decision-making. The AER has expressed the view that the inclusion of capital spending in the EBSS could lead to inappropriate incentives to defer capital outlays to later regulatory control periods.

2.1.2 Proposed uncontrollable cost categories

Section 2.3.2 of the EBSS paper (AER, 2008f2) indicates that a distribution business must provide strong grounds for the exclusion of certain cost categories from the operation of the scheme. Cost categories that are normally regarded as controllable, for example labour, materials and service provider costs, would be unlikely to qualify for exemption from the scheme. However, the AER has mentioned that certain types of spending will be eligible for exclusion, notably:

- Operating expenditure on non-network alternatives. These amounts can be deducted from the actual and forecast values used to calculate carry-over gains or losses under the EBSS.

- Approved increases or decreases in actual operating expenditure associated with recognised pass-through events.

UED is proposing that costs which fall into the groupings shown below should also be classified as uncontrollable for the purposes of calculating amounts owing or to be paid under the EBSS. The categories are:

- Debt and equity raising costs.
- Self-insurance costs.
- Insurance costs.
- Superannuation costs relating to defined benefit and retirement schemes.
- Expenditure that meets all of the necessary requirements for an approved pass-through event though without necessarily satisfying the materiality threshold.

The types of costs which feature in the list shown above are drawn principally from the final distribution determination for NSW DNSPs (AER, 2009d1). In the main, UED endorses the explanatory material which has been advanced to justify the treatment of the aforementioned cost categories as uncontrollable. The management of the particular costs would be beyond the remit of the normal business activities of a distributor.

In addition to the uncontrollable cost categories accepted by the AER for the NSW DNSPs, UED proposes the exclusion, from the EBSS, of pass through costs which fall below the relevant materiality thresholds. The argument in support of this approach is that cost pass throughs are designed to address spending changes due to imposts, the causes of which lie beyond a company's sphere of control. While there is a case for applying a materiality test to the pass through of such amounts to customers, there is little merit in applying the same materiality threshold when calculating payments under the EBSS. In the absence of the proposed exclusion, UED could be exposed to an efficiency penalty (or bonus) as a result, for instance, of a change in tax law or a change in vegetation management regulations. There would be no virtue in compelling UED to take the risk of possible penalty or bonus payments in respect of cost changes that are patently unrelated to the company's performance. Accordingly, pass through amounts which do not satisfy the materiality threshold should be exempted from consideration under the EBSS.

2.1.3 Demand growth adjustments

In section 2.3.2 of the EBSS paper (AER, 2008f2), the AER has stated that for the purposes of calculating carry-over amounts, operating expenditure projections must be adjusted for the cost consequences of any differences between forecast and actual demand growth over the regulatory control period. These adjustments must make use of the relationship between demand growth and expenditure that was established when developing the operating expenditure forecasts in the first instance. Adjustments should also only be applied to the components of operating spending which are directly affected by growth.

Regulatory precedents

UED notes that in the final determination for NSW DNSPs, (AER, 2009d1), the AER resolved not to undertake demand growth adjustments when calculating future obligations or entitlements under the EBSS. The final decision to rule out making *ex post* revisions to operating expenditure projections was essentially an affirmation of the earlier draft decision (AER, 2008k4). The AER reached a conclusion because none of the NSW DNSPs had proposed a mechanism for amending operating spending forecasts in response to changed circumstances surrounding demand drivers.

In its deliberations, the AER also expressed a view that a demand growth adjustment was not required for the EBSS to provide DNSPs with a continuous incentive to pursue efficiency gains. Specifically:

> " The demand growth adjustment was incorporated into the EBSS to prevent DNSPs from being penalised or rewarded by the EBSS for changes in demand growth over which the DNSP has no control. The risk to DNSPs of being rewarded or penalised by the EBSS for changes in demand growth is a symmetrical one. The AER considers it reasonable for the EBSS to not be adjusted for changes in demand growth if a DNSP does not regard this as necessary."

(Text drawn from AER, 2008k4).

United Energy stand-point on business volume drivers

UED believes that changes in variables such as customer numbers, peak load, and energy consumption do have a bearing on operating expenditure. In the event, therefore, that the out-turn values of these variables differ from the amounts forecast, UED believes that it is appropriate to make revisions to the operating spending projections. However, UED also acknowledges that the relationship between demand growth and operating spending is less pronounced than the measured association between demand growth and capital expenditure.

For the purpose of calculating efficiency carry-over amounts accumulated or accrued over the 2011 to 2015 regulatory period, UED is proposing to undertake the form of demand growth adjustment that has been applied in respect of carry-over values from the 2006 to 2010 regulatory period. The method of adjusting for deviations – from forecast - in the volumetric component of operating spending during the 2006 to 2010 regulatory period is described in detail in section 1.1.3. The approach, originally put forward by SP-Ausnet, was endorsed by the ESCV in its final determination (page 435, ESCV 2005a). The results from the application of the method to the efficiency carryover mechanism (ECM) for the current regulatory period have been shown in Table 1.4 and Table 1.5. The approach has merit because of its genesis in partial factor productivity analysis.

In essence, the PFP method relies upon forecasts of an output quantity index. Projections of the component output variables and estimates of the corresponding cost elasticities are therefore also required. The output growth forecast can conceivably pertain to the subject utility or to the industry as a whole. For ease of exposition, the formula for the output quantity index is reproduced below:

$$\ln\left(\frac{Output\,quantities_t}{Output\,quantities_{t-1}}\right) = \sum_i SE_i \times \ln\left(\frac{Y_{i,t}}{Y_{i,t-1}}\right)$$ **Equation 2.1**

Where:

$SE_i =$ The share of output category i in the sum of the estimated, output-related cost elasticities.

And, in each year t:

$Output\,quantities_t =$ Output quantity index.

$Y_{i,t} =$ Quantity sub-index for output category i.

The expected rate of growth of the output quantity index depends on forecasts of the relevant output quantities and estimates of the corresponding cost elasticities. PEG reported that the output growth forecast can, in principle, be that for the subject utility or for the industry as a whole (PEG, 2004). UED has prepared projections of the core output variables for its own network, and not for the industry as a whole. The forecasts for 2011 to 2015 encompass average customer numbers per annum, maximum demand across the network, and average annual energy consumption.

The output-cost elasticities will be those calculated by the ESCV (ESCV, 2005a) using the results of research undertaken by PEG (PEG, 2004) on behalf of SP-Ausnet. A fuller discussion of the elasticities is provided in section 1.1.2 of this report appendix, and the results are reported in Table 1.3. As has been noted, the elasticities were derived by PEG (PEG, 2004) using the estimated parameter values from a translog cost equation. The function had been applied by PEG, making use of data on 72 investor-owned electricity utilities with wide geographic dispersion across the USA.

The ESCV made use of the results from separate, single output variable models, that is, equations in which the influence on total costs of only one output measure (either customer numbers, peak demand or energy consumption) was examined. Each of the equations also incorporated other explanatory variables, including input prices, average rainfall (a proxy for forest cover), and measures of business conditions. The use by the ESCV of cost elasticity estimates from separate regressions is unconventional, but defensible. A virtue of the research methods applied by PEG is that the empirical work was robust, with the translog cost function well founded in theory and practice, while the data sample used was comparatively large. It would not be feasible to undertake a similar empirical exercise using exclusively Australian data because of a comparatively small number of electricity distribution businesses in Australia as a whole. The ESCV normalised the elasticity estimates by constraining the values to sum to unity. The resulting figures were 0.431 (for customer numbers), 0.272 (for peak demand) and 0.296 (for energy consumption). These coefficients can be treated as cost shares, and UED expects to apply them going forward.

The adoption of a method which is consistent with partial-factor productivity (PFP) analysis serves to ensure that realistic and accurate adjustments will be made at the end of the regulatory period.

UED has provided forecasts of the relevant output variables which will be available for comparison with actual outcomes towards the end of the forthcoming regulatory period.

2.1.4 United Energy capitalisation policy as at 01st January 2011

Distribution businesses are obliged to report changes in capitalisation policy to the AER. The requirement to do so is enunciated clearly in section 2.3.2 of the EBSS paper, (AER, 2008f2), and in section 5.7 of the Victorian F&A paper (AER, 2009e1). In the event of an alteration to capitalisation policies, distributors must provide an explanation, and a fully worked calculation which shows the effect of the change on forecast and actual operating spending.

UED would be pleased to submit a copy of its capitalisation policy to the AER upon request. At this stage, the firm anticipates no change to the policy in either the current regulatory period or during the next regulatory period. If revisions to the policy are brought about, however, then UED will act in accordance with clause 2.3.2 of the EBSS (AER, 2008f2), and will therefore:

- Adjust the operating expenditure benchmarks that have been put forward for the purpose of calculating efficiency carry-over amounts. The revised forecasts will take full account of the new policy/policies regarding capitalisation.
- Provide the AER with a comprehensive description of the changed policy.
- Assess the impact of the new policy on actual operating expenses incurred to-date.

2.1.5 Exclusion of non-network alternatives

In section 2.3.2 of the EBSS, the AER has affirmed that all operating expenditure spent on non-network alternatives will be exempt from consideration under the EBSS. In other words, the budgeted and actual operating expenditure sums used to calculate carry-over gains and losses under the EBSS will not incorporate any allowance for spending on non-network alternatives.

In its forward projections, United Energy is expecting to devote a fair share of total operating expenditure to non-network alternatives. A reasonably high proportion of recurrent outlays on non-network options will be in respect of the Demand Management Innovation Scheme (DMIS). UED is also proposing that the Demand Management Innovation Allowance (DMIA) be excluded from the operation of the EBSS. The forecasts for spending on the DMIS are presented in the demand management chapter of the main regulatory proposal for UED.

2.1.6 Treatment of recognised pass-through events

In section 2.3.2 of the EBSS paper, (AER, 2008f2), the AER has set out its policy regarding the treatment of approved increases or decreases in actual operating spending associated with recognised pass-through events. The AER has indicated that clearly identifiable pass-through components will not qualify for inclusion in the EBSS. Accordingly, the AER asserts that any increase or decrease should be exempted from the calculation of carry-over gains or losses.

United Energy concurs with the AER and believes that sanctioned increases or decreases in actual operating expenditure directly attributable to pass-through events should not be incorporated into the calculations underpinning the EBSS. Pass-through events are analysed more fully in chapter 19 of the regulatory proposal.

2.1.7 Changes in responsibilities

Section 2.3.2 of the EBSS paper, (AER, 2008f2), stipulates that the operating expenditure projections should include any necessary adjustments for changes in responsibilities that result from compliance with a new or amended law, licence, or other statutory or regulatory requirement. The types of requirement have been defined as encompassing those that can be demonstrated to arise directly from a recognised practice or policy generally applicable to similar firms participating in the National Electricity Market.

If there is a change in the types of responsibility imposed upon United Energy in the next regulatory period, then UED will identify the change, and quantify the resulting cost impacts.

2.1.8 Standard control service change

Section 2.3.2 of the EBSS paper, (AER, 2008f2), also contains a statement about the intended re-allocation of costs in the event of a re-classification of services. The AER has put forward a position that the costs of providing a service may be deducted from the forecast and actual operating expenditure sums employed for the purpose of calculating carry-over amounts if the service is re-classified away from standard control. The AER will exercise its discretion in this matter depending upon factors such as:

- The materiality of the impact on carry-over amounts.
- The potential for and magnitude of cross-subsidies; and
- Whether there is any evidence to suggest that a distribution business might have engaged inappropriately in cost shifting so as to maximise carry-over amounts.

2.1.9 Carry-over period

Consistent with section 2.3.3 of the EBSS paper, (AER, 2008f2), United Energy proposes the application of a five regulatory year carry-over period.

2.1.10 Application of carry-over values

In section 2.3.3 of the EBSS paper, (AER, 2008f2), the AER has pledged to apply all carry-over amounts, both positive and negative. The AER has also made firm its intention to undertake the various adjustments documented in section 2.3.2 of the EBSS paper. United Energy understands that carry-over values will be incorporated as a building block element in the calculation of allowed revenue for the regulatory control period which follows on from the 2011 to 2015 period.

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